# COST ESTIMATES FOR CAPITAL EXPENDITURE AND OPERATIONS & MAINTENANCE BASED ON TECHNOLOGY REVIEW

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# 1.0 Executive Summary

This report outlines the specific criteria considered in providing a cost estimate for a prospective 12 MW gross biomass-fired power generation facility (with a co-located small-log sawmill using up to 2 MW power and steam). It addresses Capital Expenditure and Operations & Maintenance estimates, and includes a Technology Review, with Request for Quotes from knowledgeable and proven vendors, based on a Process Flow Diagram. This estimates less than $40 million for the powerhouse and $8 million for sawmill (sized to 8 million board feet). Annualized O&M is less than $1 million (excluding labor, fuel procurement, equipment upgrades, or interconnection). This can be deemed an approximation in the range of plus or minus 15%.

# 2.0 Technology Review

## 2.1 *Scope of Technology Review*

As determined by the TSS Fuel Availability Study [August 15, 2008], in order to achieve the stated goal of selecting technology that optimizes cost effective generation of heat and power that utilizes the woody biomass blend available, preferred technology should be currently commercially available. That report recommends with respect to technology selection:

> "…using wood waste as fuel for power generation is not a new concept. What is new is combining the beneficial elements of forest management, fire hazard reduction, and power generation for a facility sited within the forest. Improvement in overall coordination is the aim, coupled with having a replicable design. Hence, this study proposes using conventional boiler technology that is commercially available. Alternate technologies, and whether fuel is solid, liquid, or gas, could be considered for future proposals, if such technologies evolve and meet the "commercially viable" standard. The focus of these installations is on viability, not demonstrating heretofore unproven commercial-scale technologies."[1]

Based on that recommendation and set of findings, TSS has focused its technology review on (1) conventional boiler technology, (2) required associated emissions controls, and (3) fuel-handling equipment for the fuel blend that consists of forest fuels reduction residuals, timber harvest residuals, small-log sawmill residuals, and wildlands/urban interface residuals.

A conceptual plant process flow design schematic is provided in Appendix A.

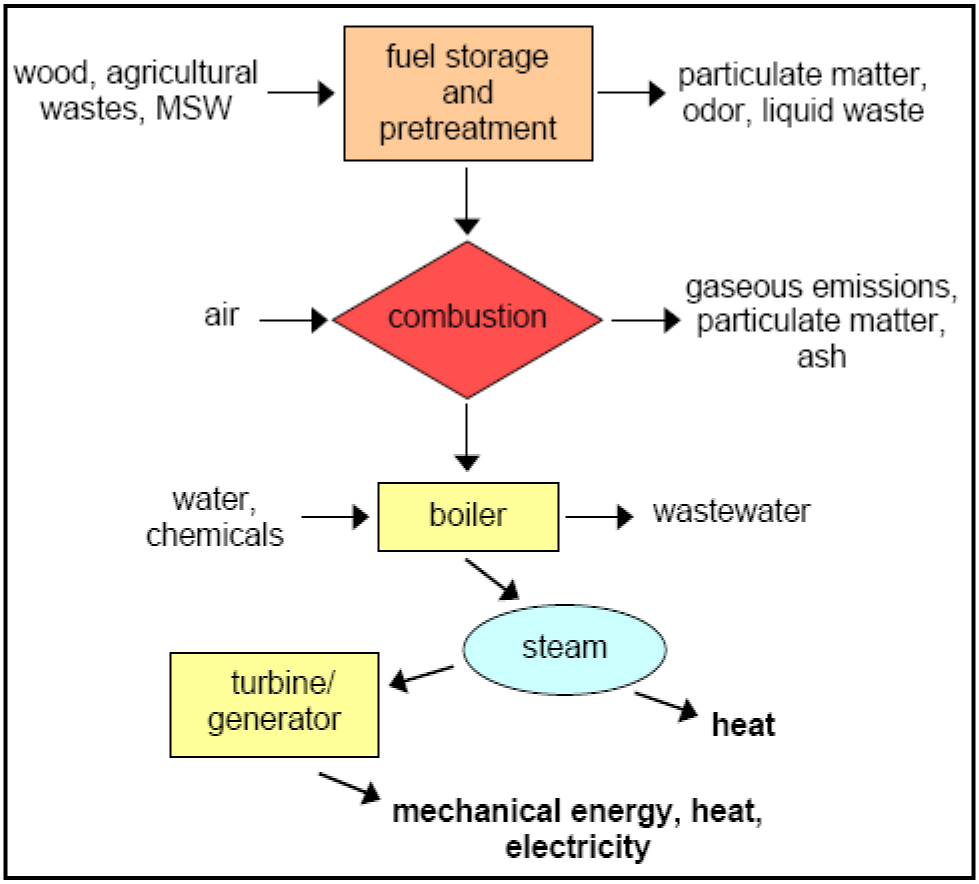
## 2.2 *Conventional Boiler Technology*

Direct-fired systems are the conventional and industry standard utilized to produce steam for heat and electricity generation from biomass in the United States today. In direct-fired systems, the biomass fuel is directly burned (combusted) in a furnace or combustion unit that then supplies heat to a boiler.

[1] "Fuel Availability Study for a Wood Waste Fired Generation Facility Sited within Southern California Edison Forest Land", prepared by TSS Consultants, 8/15/08 update, and page 31.

Figure 1 illustrates a direct-fired combustion system flow process. Direct-fired biomass systems are two types of boiler systems: (1) stoker boilers, and (2) fluidized bed boilers. The elements, advantages, and disadvantages of these two systems and their applicability to the fuel blend available are discussed in the following sections. Recommended approach for the prospective facility design is identified.

**Figure 1 – Direct Combustion Schematic**




### *2.2.1 Stoker Boiler*

Stoker boilers are the conventional commercial boiler technology deployed for direct-fired biomass combustion. This preferential selection is due to the benefits in using stoker boilers. They accept a variety of fuel types including sawdust, bark, chips, hog fuel, and shaving. Additionally, moisture content of fuel that stoker boilers accept is in a wide range of 10-50% (which is in the expected range of the prospective woody biomass fuels, particularly at the higher end of this range). This allows for a wider selection of fuel types, though it does operate best when the fuel is as homogeneous or consistent a mix as possible.

Literature reports that fuel needs to be reduced to a size of 0.25 to 2 inches to be accepted within most stoker boilers, however in practice it is observed that fuel up to 3 inches in size are readily accepted by stoker boilers without any operational issues. Limited fuel preparation and processing is required for stoker boilers compared to other biomass boiler or conversion technologies. Operational procedures are not overly technical, which allows for a broad implementation across an expanse of possible locations and skill sets. Start up of stoker boilers is relatively simple (compared to fluidized bed boilers), and do not require the use of natural gas or propane for startup. Facilities similar to the proposed SCE power plant have shown empirically that the addition and ignition of approximately 1 gallon of diesel fuel or other comparable ignition source provides sufficient startup heat for a stoker boiler.

There are a number of configurations possible, in utilizing a stoker boiler design, but there are two general stoker systems that describe the fuel distribution with respect to location of the grate.

Stokers can be described as underfeed or overfeed. Overfeed stokers place fuel on the grate and supply air from below. Fuel distribution can be achieved in a variety of ways with an overfeed stoker, generally using mass feed or spreader. In a mass feed system, fuel is added from one side of the grate and travels across it and ash exits the other side. Mass feed systems utilize vibrating grate and moving grate stokers. Spreader stokers are a commonly used design, and as the name implies, spread the fuel evenly across the grate, combusting light particles in the air and heavy particles on the grate. Because lighter particles combust immediately in the combustion gases, spreader stokers have a shorter response time compared to mass feed stokers.

A shorter response time is preferential because it allows operators a higher level of control of combustion parameters in order to achieve higher combustion efficiency. Alternately, fuel distribution has one design for an underfeed stoker where it pushes new fuel to the bottom of the combusting pile beneath the grate using a screw or ram process. This underfeed process requires fuels with lower moisture content, less than 45% (for which the prospective fuel supply meets this criteria). Underfeed stokers have a lower response time compared to overfeed stokers and high ash content when the boiler is overloaded. Overfeed stokers and their respective fuel spreading technology applications leads to higher levels of fuel combustion control.

### *2.2.2 Fluidized Bed Boiler*

Fluidized bed boilers (FBB) were developed much more recently than stoker boilers. FBBs were developed around the concept of increasing combustion efficiency to reduce the amount of criteria pollutant emissions -- oxides of nitrogen ($NO_x$), and oxides of sulfur ($SO_x$). As a result of this change in combustion technique and process, fuel in FBBs have a higher residence time compared to fuel in a stoker boiler which leads to more complete combustion. Additionally, lower temperatures experienced within the combustion chamber lend to less $NO_x$ production. Sulfur content in biomass fuels is usually negligible, but if $SO_x$ issues are present or require address, then limestone can be injected into a FBB to mitigate this emissions issue.

In FBB, particles are chipped and processed to a size generally smaller than what a stoker boiler can accept (all fuel must be less than 2” in size). Fuel is injected into the combustion chamber over a constant stream of air that is injected below the fuel to keep the fuel and air mixture completely suspended, or “fluidized”. Generally, biomass is combined with a minimum of 20% excess air for efficient combustion. Natural gas to supplement FBB combustion during startup is part of the design, where propane could be utilized in remote locations. Such minimal usage is typical to a biomass-fired power generation facility.

FBBs are much more complicated to construct, install, and operate compared to a stoker boiler. It is expected the initial capital cost of FBB equipment will be 150% to 250% increase in capital expenditures compared to a stoker boiler. Installation costs would be similar to a stoker boiler. Only marginal cost improvement may be experienced from more efficient fuel combustion. Any cost savings would be through reduced criteria emissions, or reduced emissions controls.

### *2.2.3 Boiler Recommendation*

Overall, the increased capital cost from a FBB far outweighs any potential saving. And it is found that a FBB would not satisfy SCE’s goals of providing a currently available cost-effective means of electricity and heat generation. It is recommended to select a stoker boiler that would provide the most cost effective means of electricity and heat generation with its relatively reduced capital cost requirement.

## 2.3 *Associated Emissions Controls*

Address of emission control equipment requirements is based upon selection of stoker boiler as the preferred technology. Per the TSS analysis of application regulations, a stoker boiler will require that emissions controls per SJVAPCD rules be installed to address the following criteria pollutants: particulate matter (PM), oxides of nitrogen ($NO_x$), and likely carbon monoxide (CO). Installation of respective emission control equipment is fully at the discretion of the facility owner, as long as emission limits are not exceeded and SJVAPCD BACT requirements are satisfied. It is recommended that specific equipment and practices be utilized for a prospective facility, namely electrostatic precipitator for PM, SNCR with urea for $NO_x$ and optimization of combustion efficiency for CO (See the TSS Environmental Analysis report).

### *2.3.1 PM Emissions Controls*

There are multiple PM control technologies that can be employed on a biomass-fired power generation facility. They include: settling chambers, cyclones, multi-cyclones, electro-static precipitators (ESP, electrostatic filter), bag filters (baghouse), spray chambers, impingement scribblers, cyclone spray chambers, and venturi scrubbers. To determine a cost-effective application of PM controls for this prospective project design, this technology review will layout and compare merits of a baghouse and ESP. The other technologies listed either provide control measures that are ineffective at levels required by SJVAPCD, or are effective but the cost burden of that technology places it out of range of consideration.

A baghouse is a set of permeable filters that captures particles on filter cloth that must be replaced periodically (replacement interval depends highly on the ash content of fuel, but generally cloth life is 2-3 years with low to moderate ash content in fuel, such as would be similar to forest-sourced fuel). Baghouses are a proven technology, can remove over 99% of PM, and the capital installation cost is comparable with an ESP (estimated at $700,000 - $1.5M). Cost of replacing the baghouse filters each 2-3 years is similar to the cost of power draw of an ESP over a similar time period. The comparative operational costs of the baghouse filter and the ESP may change as energy prices fluctuate. Drawbacks include that the baghouse is sensitive to filtering velocity, condensation and humidity impact filter efficiency, and the flue gases must be cooled to approximately $480^{O}$ F. Such operational limitations, which also come with additional space requirements, tend to place it outside the range of consideration for a prospective project.

An ESP provides an electrical field to capture particles as they flow within a charged field. Benefits include that ESPs have a high removal rate, upwards of 99%, can collect very small ash particles from the flue gas (fly ash), can operate in high temperature ranges up to $900^{O}$ F, and can handle high flue gas rates. Parasitic draw is not insignificant. Maintenance is minor, unless corrosive materials enter the ESP, which would require a full change-out of the filters that is more time-consuming than technical. ESP has similar operational costs (power draw opportunity cost) as the baghouse maintenance cost. Drawbacks of ESPs include that they require high voltages so personnel must take safety precautions, and removal efficiencies may deteriorate during startup and non-standard operations.

Thus, an ESP is the optimal technology for PM control, given its range of operation, removal efficiencies, and low maintenance costs. These features reduce the amount of mitigation required for PM emissions. ESPs are recognized by environmental regulators as an effective and proven technology for PM controls, and are utilized widely on biomass power generation facilities in the western United States, where this prospective facility is to be sited.

### *2.3.2 $NO_x$ Emissions Controls*

The optimal $NO_x$ control would be to lower the combustion temperature experienced by the fuel air mixture. However, this reduces combustion efficiency of the facility, and requires tighter operational oversight by facility personnel. Alternately, two extant $NO_x$ controls could be used for biomass facilities, selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Efficiency of these two methods, and past applicability of regulations by air districts, is covered in more detail in the TSS Environmental Analysis report.

SCR utilizes ammonia in the presence of a platinum, titanium, or vanadium oxide catalyst. SCR is extremely effective at reducing $NO_x$ at a rate of up to 95%, however it is likely the catalyst will be deactivated by fouling, poisoning, or blockage from flue gas contents, typical to biomass power. Replacement of the catalyst is a labor and capital-intensive process and may reduce the overall capacity factor for the facility given necessary downtimes for catalyst replacement.

SNCR, as the name implies, does not use a catalyst and thus overcomes the major drawback of the SCR process. SNCR uses ammonia or urea for $NO_x$ reduction is injected into the flue gas at high temperature, $1550^{O}$ F to $1690^{O}$ F, and has the potential to reduce $NO_x$ emissions 60-90%. Flue gas temperature controls are extremely important to optimize $NO_x$ reduction, with either SCR or SNCR. Specifically, ammonia or urea will begin to be oxidized to NO (which is considered a $NO_x$ emission), if high temperature conditions exist (above optimal range noted above), or will fail to react with the $NO_x$ at low temperatures.

Thus, SNCR is the optimal technology for $NO_x$ control. Given the small-scale of the prospective facility, urea would be the optimal reagent because it would avoid issues associated with the transportation of hazardous chemical that anhydrous or liquid ammonia present.

### *2.3.3 CO Emissions Controls*

CO controls applied to facilities that utilized biomass fuels most often consist of improved management and combustion efficiency. Technology application, a catalytic converter, is available for CO emissions reduction, however it is not a reliable means of reduction, and the additional cost outweighs any potential benefit.

Catalytic converters provide a technological means for directly reducing CO (and a variety of other emissions). They are extremely effective, above 95%, when applied in conditions that can be tightly controlled where flue gases are extremely homogeneous. This is not the case for small-scale biomass facilities. Instead, the flue gases experienced in biomass facilities are heterogeneous in nature, and will often deactivate catalytic converter by fouling, poisoning or blocking the catalyst. This renders the converter ineffective and is a costly item to repair multiple times. Thus, a catalytic converter would not provide a cost-effective means for reduction of CO emissions, compared to the alternative of improved management and combustion efficiency.

Improved management and combustion efficiency involves high levels of operational controls to ensure an ideal air ratio to ensure complete combustion, adequate air-fuel mixing, and heat output from the boiler itself. Due to diversity of size, texture, volume, and wood type, this would be an ongoing adjustment, not a one-time set-point. Gas recirculation can be applied to ensure complete combustion of any hydrocarbons and CO contained within flue gases. Optimization of biomass boilers can lead to a significant decrease in CO emissions, ranging from a 50%-97% reduction compared to a non-optimized unit. Cost of such additional attention to the equipment is included in and does not appreciably increase the anticipated cost of operation.

## 2.4 *Fuel-handling Equipment*

Each step of the fuel handing and processing is a necessary part of the biomass power facility. Fuel handling equipment is generally standard, somewhat automated, but requires monitoring from the control room. Manual systems can be employed in addition to or in lieu of automated processing systems, such as using a front-loader for conveyance of fuel after it is sorted and impurities are removed. Biomass fuel preparation can be broken out into major steps: receiving, processing including buffer storage, and fuel metering. This section of the report addresses the equipment needed for each of those steps, from delivery to the power plant. (This section does not address fuel processing and transport prior to delivery at the power plant, as such is specifically described in the separate TSS Fuel Procurement Plan).

Biomass receiving is the interface between truck delivery and fuel storage. Various scales of truck fuel delivery and receiving installations exist. For the scale of the prospective facility, it is recommended that a hydraulic dumper be utilized that can fully lift a semi-trailer and dump fuel as it is most cost and time-effective option for fuel deliveries. Other options for fuel delivery are more labor-intensive and less time-efficient. The hydraulic dumper lifts the truck and trailer up to an angle of $75^{O}$ where the fuel is moved to a live-bottom receiving hopper, and then a stacker moves the fuel into piles for additional processing.

Processing fuel requires a system that separates, sizes, and removes metals or non-combustibles from unprocessed fuels. Sizing equipment (a disc screener, for example) will remove oversized particles and bypass undersized particles. Oversized particles are moved to a grinder for size reduction. This processed fuel is appropriately sized for the selected boiler technology. It then has non-combustibles and metals removed, and is transported to a silo for storage and later use. This silo storage acts as buffer storage that has a live bottom that moves fuel from bottom of storage to the collection conveyors, ensuring real-time control of the fuel utilization rate.

Fuel metering is the last step that controls the fuel input into the boiler. From the collection conveyor, an auger feeds fuel into a surge bin. Fuel is then metered from the surge bin through a rotary airlock, and is pneumatically transferred into the boiler combustion chamber.

Thus, the equipment recommended includes a combination of truck scales, hydraulic dumper/truck tipper, conveyors, screeners, fuel meters, pneumatic support, and front-end loaders. Such equipment can cost-effectively be acquired.

# 3.0 Capital Cost Estimates

The method used to determine estimates for Capital Expenditures and Operations & Maintenance (O&M) is based on that typically used it the wood-waste industry. It includes acquiring quotes from responsible vendors, which required providing them with a comprehensive description of a prospective facility design, and the power system components for which they were being asked to provide a price quote. Estimates for O&M are based on a working knowledge of the industry.

## 3.1 *Request for Quotation Process*

In order to produce the most cost-effective results from the process, it was determined a Request for Quotes (RFQs) would be issued for each of the four pieces of critical capital expenditures for power system components: boiler, cooling tower, electrostatic precipitator, and turbine. This would allow the RFQ process to target preferred vendors with a track-record of being responsive and responsible bidders, in supplying proven technology and support services regarding a biomass power plant of the size targeted, by component. An RFQ collects requested information from prospective vendors for a prospective project that is still in its initial planning phases. Eleven vendors chosen met these requirements and were supplied with the respective RFQ for their technology. In order to evaluate the “short” list of technology vendors, specifications were identified, as follows. The RFQ was sent to the eleven vendors listed below in Table 1. A full copy of the RFQ is contained in Appendix B.

**Table 1 – Vendor RFQ Distribution Summary**

| Vendor Name | Vendor Location |
|---|---|
| **BOILER** | |
| Factory Sales Engineering | Covington, LA |
| Cerry | San Nicolas de los Garza, Mexico |
| Indeck Keystone Energy, LLC (represented by Christian Power Equipment) | Erie, PA |
| **COOLING TOWER** | |
| GEA Power Cooling | Lakewood, CO |
| Research-Cottrell Cooling, Inc. | Somerville, NJ |
| SPX Cooling Technologies, Inc. (represented by Christian Power Equipment) | Overland Park, KS |
| **ELECTROSTATIC PRECIPITATOR** | |
| PPC Industries | Longview, TX |
| Clyde Bergemann EEC (represented by Christian Power Equipment) | Hanover, MD |
| Hamon Research-Cottrell | Somerville, NJ |
| **TURBINE** | |
| TMC (represented by Christian Power Equipment) | Walnut Creek, CA |
| Dresser Rand (represented by Ross Equipment & Process Solutions Company) | Westminster, CA |

The RFQ was prepared with the following parameters and information requests:

- Project overview – general location information (Central California, elevation), general biomass power generation facility process flow diagram;
- Project objective – develop a biomass power generation facility of 10 MW net (boiler at 12 MW gross, 100,000 lbs/hr);
- Configuration – Process Flow Diagram was provided (see section 4.5 in this report);
- Technology requirement – various, depending on which technology: boiler, turbine, ESP, cooling tower, as was provided in a one-page descriptor for each system component;
- Air emissions – facility to be located in a non-attainment area for criteria pollutants ($NO_X$, $SO_X$, CO, $PM_{10}$);
- Feedstock parameters – principally forest woody biomass at 40-50% moisture content. Heating Value: 7,000 to 8,500 BTU/dry lb.;
- Contents of response submittal – responses were to include a breakdown of budgetary quotation and additional expenses (installation) if necessary;
- Deadline for response – January 30, 2009;
- Contact – TSS contact information supplied.

After electronic distribution of the RFQ to vendors on January 9, 2009, TSS followed up with each vendor for verification that the RFQ had been received and understood. From January 12 through January 30, TSS was in daily contact with the vendors through e-mail and phone conversations clarifying technical, financial, and general questions submitted. Clarifications often required supplying general information regarding the sizing of the facility, appropriate environmental regulatory requirements, and general location information (Central California).

## 3.2 *Capital Cost Vendor Response*

Nine vendors responded to the RFQ with sufficient information by the RFQ response deadline, and were included in the analysis to determine a capital cost estimate. The two vendors that did not respond are Cerry (Boiler) despite multiple unsuccessful attempts to communicate, and GEA Power Cooling (Cooling Tower) who considered the RFQ too small to quote. Vendor responses are included in Appendix C. Table 2 summarizes the quotations that were provided for each of the four types of technologies. Vendor responses are included in Appendix C.

**Table 2 – Vendor Technology Capital Cost Estimate**

| Vendor Name | Vendor Estimate |
|---|---|
| **BOILER** | |
| Factory Sales Engineering | $6,720,000 |
| Indeck Keystone Energy, LLC (represented by Christian Power Equipment) | $8,490,000 |
| **COOLING TOWER** | |
| Research-Cottrell Cooling, Inc. | $421,000 |
| SPX Cooling Technologies, Inc. (represented by Christian Power Equipment) | $525,000 |
| **ELECTROSTATIC PRECIPITATOR** | |
| PPC Industries | $1,137,000 |
| Clyde Bergemann EEC (represented by Christian Power Equipment) | $750,000 |
| Hamon Research-Cottrell | $1,450,000 |
| **TURBINE** | |
| TMC (represented by Christian Power Equipment) | $4,470,000 |
| Dresser Rand (represented by Ross Equipment & Process Solutions Company) | $5,300,000 |

## 3.3 *Aggregated Cost Estimate*

After review of the vendor quotations, it was determined that the lowest bidders were the preferred vendors for each respective technology. Each had supplied quotes that were complete and only required minor adjustments to appropriately account for all project needs. Specifically, the boiler low quote (Factory Sales Engineering) required mark-up to account for delivery to site; and the ESP low quote (Clyde Bergemann) required mark-up to account for insulation that was not included in the quote. The cooling tower and turbine quotes did not require modification to meet the project-specific requirements. Based on experience with a facility of similar size and location, estimates were made for fuel handling equipment, insurance, legal, and permitting service costs. Capital cost estimation for a 12 MW gross facility is provided in Table 3.

**Table 3 – Recommended Capital Cost Estimate**

| Capital Cost Component | Cost Estimate |
|---|---|
| Boiler (Factory Sales Engineering) | $6,790,000 |
| Steam Turbine (TMC – Christian Power Equipment) | $4,470,000 |
| Electrostatic Precipitator (Clyde Bergemann EEC) | $952,500 |
| Cooling Tower (Research-Cottrell Cooling, Inc.) | $421,000 |
| Fuel Handling Equipment | $1,500,000 |
| Other required equipment (i.e. SNCR, CEMS, feedwater pump, deaerator, reverse osmosis unit, condensate pump, etc.) | $3,026,640 |
| **SUBTOTAL (EQUIPMENT)** | **$17,160,140** |
| Construction Contractor Cost[2] | $12,870,105 |
| **SUBTOTAL (CONSTRUCTION)** | **$12,870,105** |
| Engineering[3] | $1,951,966 |
| **SUBTOTAL (ENGINEERING)** | **$1,951,966** |
| Insurance | $265,927 |
| Legal Services | $500,000 |
| Permitting | $1,000,000 |
| Construction/Project Management | $530,000 |
| Contingency (15% of Equipment, Construction, Engineering) | $4,797,332 |
| **SUBTOTAL (MISCELLANEOUS)** | **$7,093,259** |
| ***GRAND TOTAL (WITHOUT INTER-CONNECTION)*** | ***$39,075,470*** |
| ***Grand Total Cost Per KW Nominal (without inter-connection)*** | ***$3,256*** |
| Transmission Inter-connection | $600,000 |
| ***GRAND TOTAL (WITH INTER-CONNECTION)*** | ***$39,675,470*** |
| ***Grand Total Cost Per KW Nominal (with inter-connection)*** | ***$3,307*** |

For planning purposes, it is generally assumed that capital costs are front-loaded, 75% upfront with 25% spending occurring in year 2. Operational experience shows that facilities perform well with standard maintenance for decades (in excess of 20 years), even while industry standard proformas consider plant life to be 20 years, particularly with the preventative maintenance identified for major equipment (see section 4.4 of this report).

[2] Estimated to be 75% of equipment cost subtotal
[3] Estimated to be 6.5% of combined equipment and construction subtotals

Also for planning purposes, the resale of waste heat or use of waste heat for secondary processes was not considered within this capital cost estimate or financial analysis conducted (waste heat not included in efficiency calculations). A condensing turbine was solicited (and ultimately recommended) which results in reduced amounts of excess/waste heat discharged from the turbine. It is expected that the benefit provided by potential excess steam generated from the power facility use for purposes other than use at the proposed sawmill would be deminimis.

### 3.4 *Small-Log Sawmill Estimated Cost*

The proposed biopower generation facility includes the potential to co-locate a small-log sawmill for timber product production and biomass fuel production. With such a configuration, there is potential to share resources between the two co-located facilities to reduce overall operations and maintenance costs, including shared personnel and fuel handling equipment. It is estimated that a small-log sawmill sized at 12-15 MMBF per year (million board feet) co-located at a prospective biopower generation facility site would cost in the range of $7.8M to $11.8M (sawmill design is considered within this cost estimate).

## 4.0 Operations and Maintenance Estimates

### 4.1 *Operations and Maintenance (O&M)*

Estimated operation and maintenance expenses are determined by experience in developing similar-sized facilities, while accounting for site-specific considerations. Typically, in this industry, O&M can be broken town into two general categories: short term maintenance and general operational expenses, as follows. It excludes the labor cost and fuel acquisition cost.

**Short-term maintenance expenses estimated at $150,000:**

- Consumables
- Phone/Utilities
- Vehicles and grounds maintenance
- Annual preventative maintenance and spare parts
- Outside services

**Operational Costs estimated at $848,000:**

- Water and chemicals
- Air permit fees, including fees for criteria pollutant emissions
- Leased equipment
- Land lease
- Project support, e.g. environmental & safety training
- Plant insurance, and Property taxes

## 4.2 Excluded Fuel Costs

Cost of fuel acquisition is addressed separately in the Fuel Procurement Plan. Such a separate address is standard in the industry, particularly due to complexity of the fuel sourcing, which is impacted by availability, which in turn is influenced by seasonal considerations, competing markets, and variable transport costs. It includes in-woods fuel handling equipment that needs to be acquired, either through contracted service or by capital expenditure (with recommendation for how to make that decision).

## 4.3 Excluded Labor Costs

Labor requirement is noted as a separate line item to the other operating and maintenance costs. TSS estimates that 17 individuals will be required to operate the proposed facility, based on plants of similar size, location, and chosen technology. Labor expenses are dependent on the performance of the facility, particularly the capacity factor (or operational hours per year). For this cost estimate, that factor is deemed to be 85%. Table 4 describes the estimated labor costs and labor rates, which totals roughly $1.5 million. It assumes 2080 operational hours per year, 8% overtime for hourly workers, and a burden rate of 33%.

**Table 4 – Estimated Labor Cost and Rates**

| Description | No. | Salary or hourly rate[4][5] |
|---|---|---|
| Plant Manager | 1 | $110,000 per year |
| Fuel Procurement Specialist[6] | 1 | $40,000 per year |
| Equipment Operator | 2 | $22.25 per hour |
| Control Room Operator | 4 | $29.26 per hour |
| Auxiliary Operators | 4 | $25.31 per hour |
| Instrument Technician | 1 | $32.71 per hour |
| Mechanics | 2 | $29.26 per hour |
| Maintenance Foreman | 1 | $33.79 per hour |
| Office Mgr | 1 | $40,000 per year |

## 4.4 Excluded Equipment Repairs

In addition to the normal maintenance required for the power plant on an annual basis, there are major pieces of equipment that have to be tested, inspected and repaired on a 3 to 5 year interval. This equipment consists of the steam turbine generator (STG), boiler tube and refractory repair, ID fan inspection and balance, feedwater pump rebuilds, and other smaller equipment repairs or replacements. Also there are normally smaller items that are desired additions to the plant to

[4] Burden Rate is defined as necessary expenses such as employment taxes and benefits in excess of salary or wages.
[5] Labor rates based on common rates for similar facilities in California.
[6] The annual salary noted is for ½ time.

increase operability and reduce maintenance costs, increase performance, and keep the plant updated with advancements of technology that occur during the life cycle of a power plant. Depending upon the financial system utilized, such would need to be planned for and recorded in the typical O&M budget, or as part of the future-year capital upgrades. As such, the authors have not included these costs in the annualized O&M totals, in the final section of this report.

| | Item: | Frequency | Estimated cost |
|---|---|---|---|
| 1. | Steam Turbine Generator inspection and refurbish | 5 years | $250,000 |
| 2. | Boiler refractory and tube work | 3 years | $100,000 |
| 3. | ID Fan and other fan inspection refurbishment | 5 years | $25,000 |
| 4. | Feedwater pump repair | 5 years | $50,000 |
| 5. | Misc small equipment repair replacement | 2 years | $40,000 |
| 6. | Technology upgrades, controls, software, equipment | 2 years | $25,000 |

## 4.5 *Total Annualized O&M Costs*

Annual estimated operations and maintenance costs are summarized below:

- $150,000 – Short term maintenance expenses
- $848,000 – Facility annual operational costs
- $998,000 – Preliminary O&M (without labor, fuel procurement, equipment upgrades)
- $1,482,759 – Labor cost
- $2,480,759 – Estimated Annual O&M (without fuel procurement, equipment upgrades)

# Appendix A. Conceptual Plant Design, Process Flow Diagram

# Appendix B. Request for Quotation

Sample cover letters, and RFQ packets are included in this sector for each technology a quotation was requested.

# Appendix C. Request for Quotation Responses